# Cost/Performance Comparisons of Alternative Cooling Systems

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## ABSTRACT

In 2002 EPRI and the California Energy Commission published a comparative analysis of the costs, performance and environmental effects of alternative power plant cooling systems for conditions prevalent in California. This paper summarizes the results of a subsequent study conducted under EPRI sponsorship which extends that work to conditions representative of sites elsewhere in the U.S. and to additional cooling system and plant types.

Performance information, equipment costs and power requirements are compiled and correlated for the major components of cooling systems of all types including cooling ponds. The information is assembled and combined with costs estimated for other important elements of a complete cooling system to generate system cost and power use correlations as a function of controlling design variables. These correlations are used to develop cost-performance comparisons at selected sites for a range of climates.

While the report presents material on recirculating wet systems with cooling ponds, hybrid (wet/dry) systems of the water conservation type and the Heller system (used primarily in Eastern Europe and the Middle East) with a barometric spray condenser and a natural draft, air-cooled heat exchanger, the paper focuses primarily on recirculating systems with mechanical-draft wet cooling towers and dry systems with mechanical-draft air-cooled condensers. Specific attention is given to the cost of water and its influence on the comparative economics of alternative cooling systems.

The cost comparisons are between optimized systems of each type and include, in addition to the capital cost of the equipment, the system power costs, the O&M costs and the costs imposed by heat rate penalties or capacity reductions attributable to cooling system limitations. The comparison methodology is presented in some detail to assist those who may wish to conduct comparative analyses for specific conditions of interest.

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## Introduction

Pressures to reduce consumption of water in power plants are increasing, not only in water-short regions of the U. S. West and Southwest but also in regions where water is plentiful. These pressures arise from regulatory concerns other than water conservation such as the desire to reduce impacts to aquatic organisms, eliminate any discharge streams or avoid problems with visible plumes or drift from wet cooling towers.

As a result, the California Energy Commission Public Interest Energy Research (CEC-PIER) Program and the Electric Power Research Institute (EPRI) sponsored studies [1], [2] to assist regulatory and utility decision makers in understanding the performance, economic and environmental tradeoffs among the alternative cooling systems and in making the appropriate system choices for a variety of plant types and site locations. This paper summarizes some of the results of the more recent EPRI study. [2]

## Methodology

The EPRI study [2] was conducted through a set of case studies covering the range of climates encountered throughout the United States and the most common plant types now being constructed. The methodology was the following. For each site and plant type, two optimized cooling systems, one wet and one dry, were defined. "Optimized," in this context, means the cooling system which results in the lowest annualized cost of plant operation including capital cost, cooling system power costs, cooling system O&M costs and any penalty cost for increased plant heat rate or limited plant output resulting from performance limitations imposed by the cooling systems. The systems are then compared on the basis of capital costs (including all costs influenced by the choice of the cooling system from the turbine flange to the pant boundary) and annualized costs, including all penalties chargeable to any constraint imposed by the choice of cooling system.

## Cases Studied

Sites

Case studies were conducted at five sites. They are

- Case 1: Hot, arid conditions typical of California, Nevada, Arizona, New Mexico and others
- Case 2: Hot, humid conditions typical of many states in the Southeast.
- Case 3: Arid conditions with extreme temperature ranges as are found in the Northern Plains (Wyoming, Montana, North Dakota, etc).

- Case 4: Moderate (cool and dry) conditions as are found in much of the Northeast (New York and New England) and the Northwest (parts of Oregon and Washington).
- Case 5: Moderate (warm and humid) conditions typical of the Midwest (Illinois, Indiana, Ohio, and others)

Table 1 and Figure 1 display the important meteorological characteristics of each site.

| Case No. | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|
| | | | | | |
| Climate Type | Arid, hot | Humid, hot | Arid, extreme | Moderate, cool | Moderate, warm |
| | | | | | |
| Location | El Paso, TX | Jacksonville, FL | Bismarck, ND | Portland, OR | Pittsburgh, PA |
| | | | | | |
| Elevation (ft) | 3,918 | 30 | 1,660 | 39 | 1,224 |
| Latitude (deg) | 31.80N | 30.50N | 46.77N | 45.60N | 40.50N |
| Longitude (deg) | 106.40W | 812.70W | 100.70W | 122.60W | 80.22W |
| | | | | | |
| Ambient Dry Bulb (F) | | | | | |
| Annual average | 64.7 | 67.5 | 42.2 | 53.6 | 50.9 |
| | | | | | |
| Summer (June through Sept.) | | | | | |
| Summer average | 80.2 | 78.5 | 65.4 | 65.5 | 69 |
| Median of extreme highs | 105 | 98 | 100 | 100 | 92 |
| 0.4% occurrence | 102 | 95 | 94 | 91 | 89 |
| 1.0% occurrence | 99 | 93 | 90 | 87 | 88 |
| 2.0% occurrence | 96 | 91 | 86 | 83 | 84 |
| | | | | | |
| Winter | | | | | |
| 97.5% occurrence | 30 | 36 | -9 | 31 | 13 |
| 99.0% occurrence | 25 | 32 | -16 | 27 | 7 |
| 99.6% occurrence | 21 | 28 | -21 | 22 | 1 |
| Median of extreme lows | 15 | 24 | -28 | 18 | -3 |
| | | | | | |
| Ambient Wet Bulb (F) | | | | | |
| Annual average | 50.1 | 61.8 | 36.8 | 48.5 | 50.9 |
| | | | | | |
| Summer (June through Sept.) | | | | | |
| Summer average | 59.3 | 70.6 | 55.3 | 56.9 | 60.6 |
| Median of extreme highs | 72 | 82 | 77 | 73 | 78 |
| 0.4% occurrence | 70 | 80 | 73 | 69 | 75 |
| 1.0% occurrence | 69 | 79 | 71 | 68 | 73 |
| 2.0% occurrence | 68 | 79 | 69 | 66 | 72 |

**Table 1: Site Geographical and Meteorological Information**

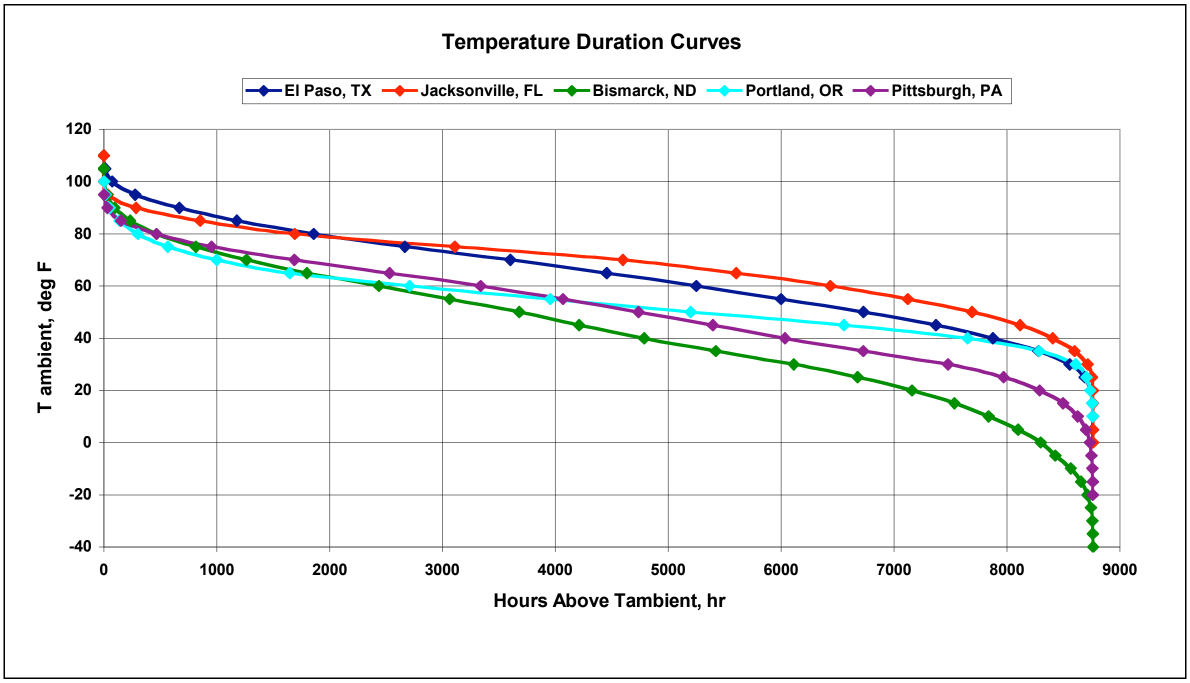



**Figure 1: Site Temperature Duration Curves**

## Plants

At each of the five sites, a 500 MW gas-fired, combined-cycle plant (CCPP) and a 350 MW coal-fired plant were considered. Important plant characteristics and steam turbine output correction curves are given in Tables 2 and 3 and Figures 2 and 3.

| Quantity | Value |
|---|---|
| Nominal plant capacity, MW | 500 |
| Configuration | 2 x 1 |
| Gas turbine output, MW | 330 (2 x 165 MW per turbine) |
| Steam turbine output, MW | 170 |
| Steam turbine exhaust flow, lb/hr | 1.1 x $10^6$ pounds per hour @ 5% moisture |
| Design turbine back pressure, in Hga | 2.5 in Hga; ($T_{cond}$ = 108.7 ºF) |
| Cooling system heat load, Btu/hr | 985. x $10^6$ Btu/hr |
| Steam turbine heat rate, Btu/kWh | 9,200 (at 2.5 in Hga) |
| Heat rate correction curve | See Figures 2 and 3 |
| Max. Allowable Backpressure, in Hga | |
| --with wet cooling | 5.0 |
| --with dry cooling | 8.0 |

**Table 2: Plant Characteristics for 500 MW Combined-cycle Plant**

| Item | Coal Plant |
|---|---|
| Plant Capacity, MW | 350 |
| Specific Steam Flow, lb/hr/MW | 7,150 |
| Design Heat Rate, Btu/kWh | 9,000 |
| Heat Rate Correction Curve | See Figures 2 and 3 |
| Back Pressure Limit, in Hga | |
| --with dry cooling | 8.0 |
| --with wet cooling | 5.0 |

**Table 3: Plant Characteristics for 350 MW Coal-fired, Steam Plant**

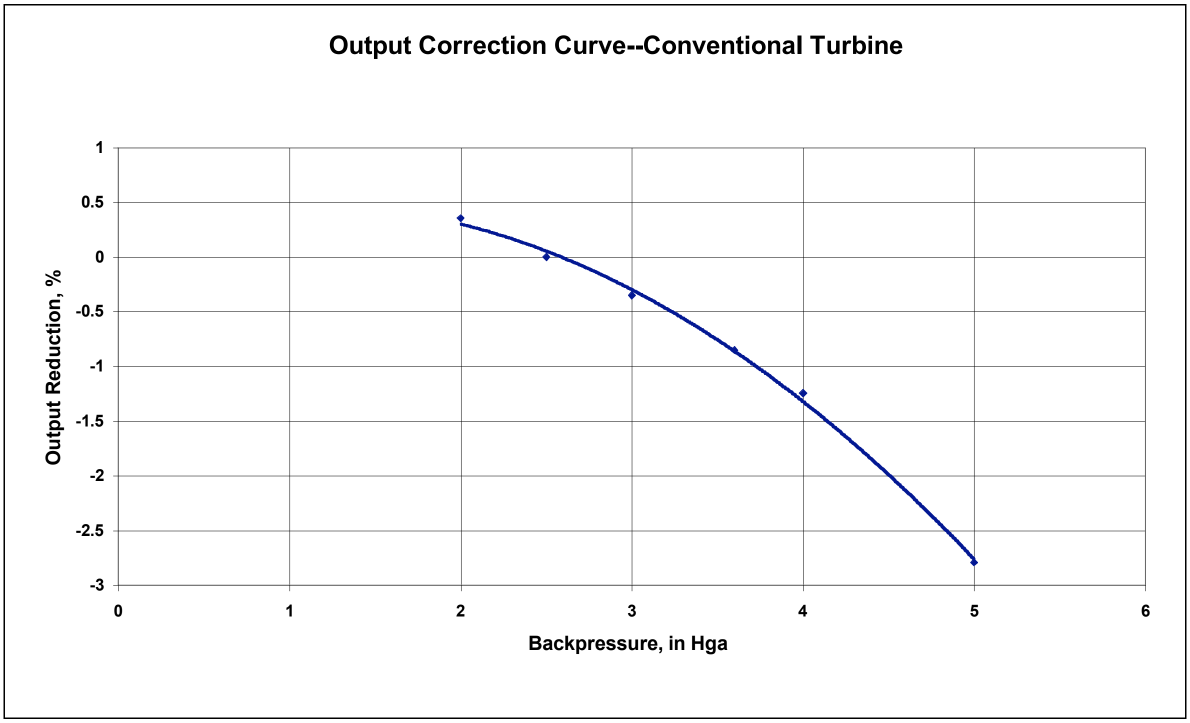



**Figure 2: Steam Turbine Output Correction Curve for Wet Cooling**

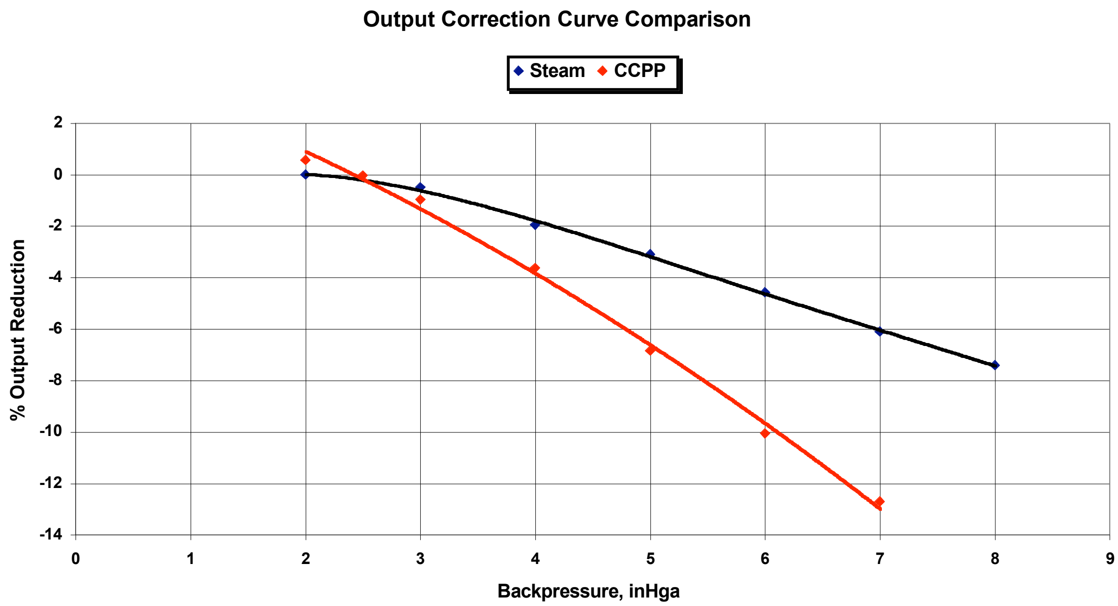



**Figure 3: Steam Turbine Output Correction Curve for Dry Cooling**

## Results

Capital and annual costs were determined for both wet and dry cooling systems for both plant types at all five sites for the site and plant characteristics described previously. Additional assumptions built into the optimizations include:

Value of energy: $35/MWh
Maintenance costs: 1.5% of capital cost (dry systems)
3.0% of capital cost (wet systems)
Annualization factor: 0.08 (based on 30 year life and 7% discount rate)

The optimization curves for a dry system on a combined-cycle plant at each of the five sites are shown on Figure 4.

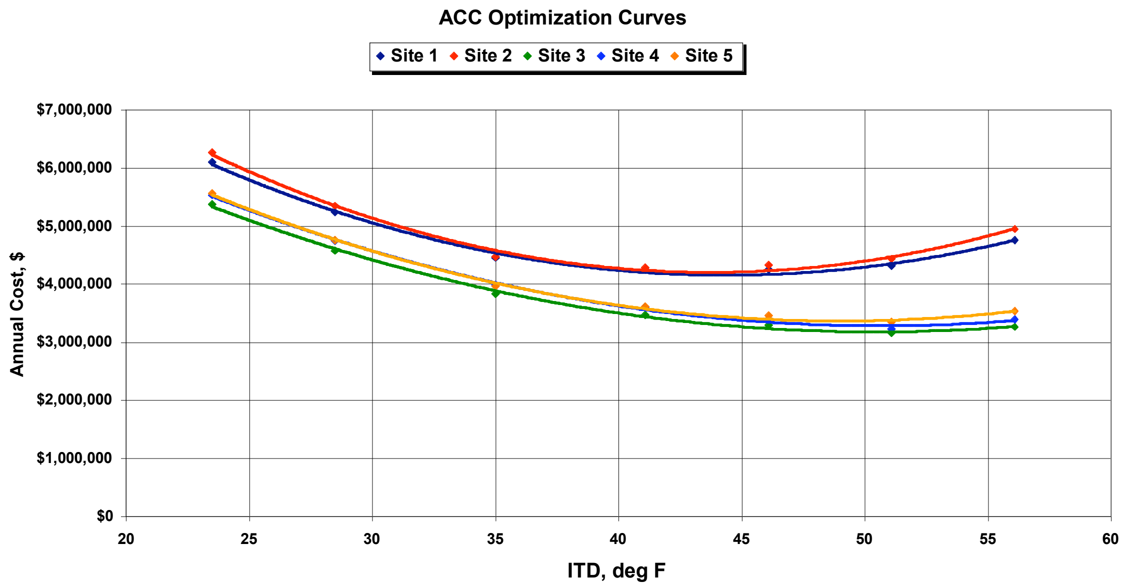



Figure 4: Optimization Curves for Dry Systems on Combined-cycle Plants

Sites 1 and 2 have higher temperatures throughout the year and thus have higher penalty costs than do Sites 3, 4 and 5. As expected, these sites optimize with larger and more expensive air-cooled condensers ACC's [corresponding to lower Initial Temperature Differences (ITD's)]. Sites 3, 4 and 5 all optimize at an ITD of around 50 to 52 F. Modest differences in the annual costs at these sites are related to the number of hours per year that fan power can be reduced while maintaining the backpressure at 2. in. Hga or above.

The optimization process of wet systems is somewhat more complicated since tradeoffs between the condenser and the tower must be explored over values of the range and the approach. However, for wet systems designed to maintain a backpressure of 2.5 in Hga at the 1% wet bulb, the energy and capacity penalty costs are negligibly small. Figure 5 shows the variation of annual costs for differing choices of range and approach for the desert site.

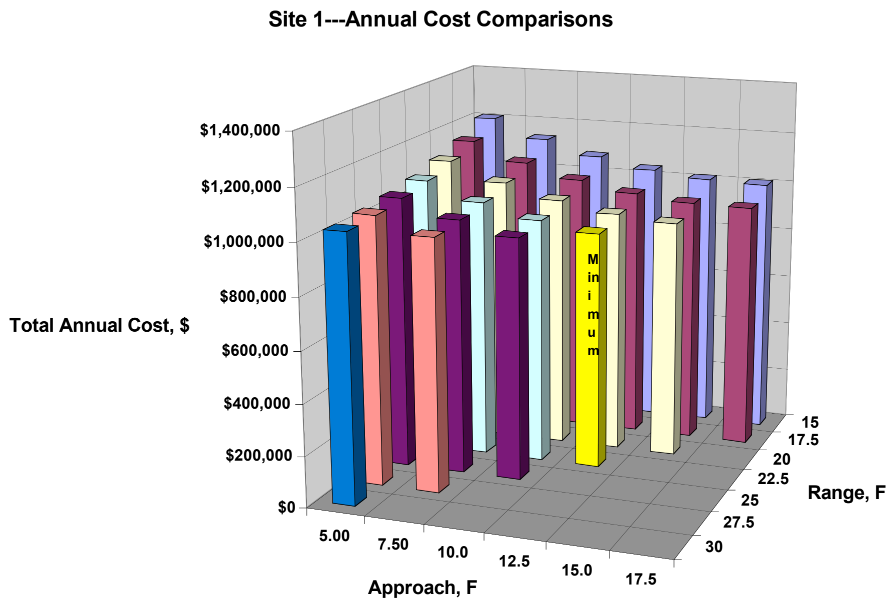



Figure 5: Wet System Optimization

Figures 6 and 7 display the capital and annual cost ratios of the optimized dry and wet systems for the five sites for both combined-cycle (Figure 6) and coal (Figure 7) plants.

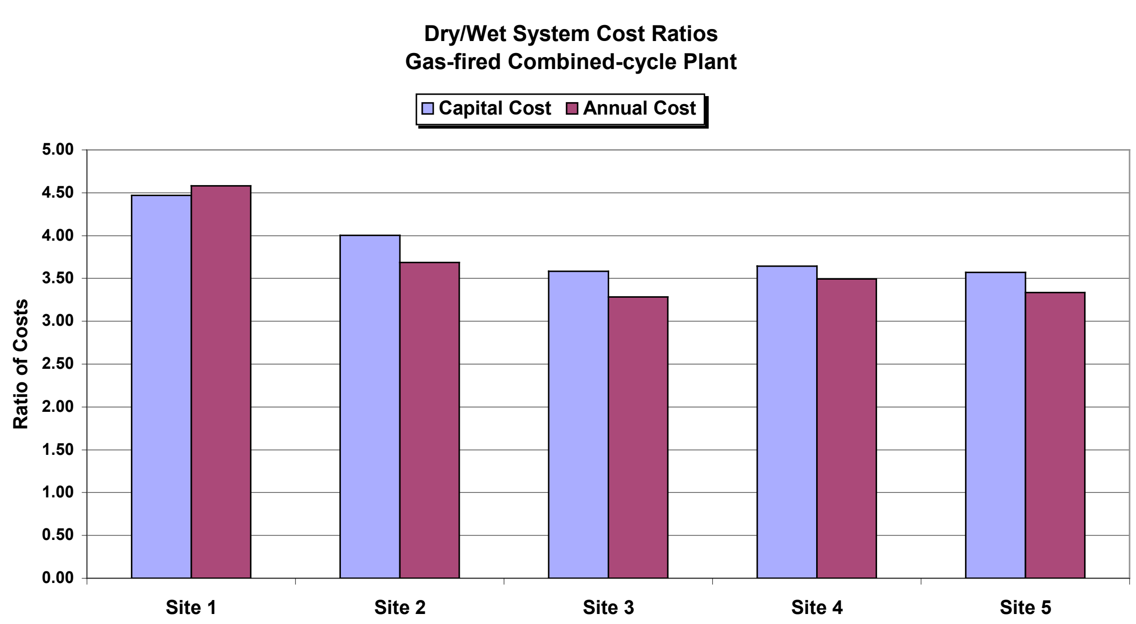



**Figure 6: Comparison of Costs for Gas-fired CCPP's**

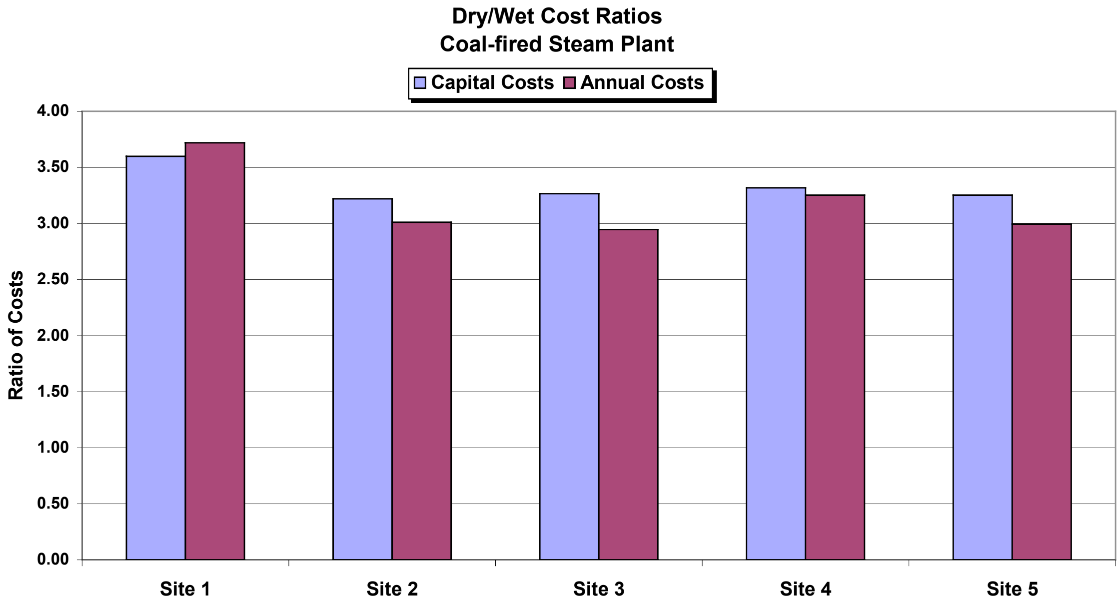



**Figure 7: Comparison of Costs for Coal-fired Plants**

For combined-cycle plants, the capital and annual cost ratios vary from 4.5 to 3.5 depending on site meteorology. For coal plants, the ratios are lower, in the range of 3.5 to 3.0, since the ACC's optimize at a smaller size, as will be discussed below.

## Effect of plant type

The choice of the optimum ACC is affected by the performance characteristics of the type of plant at which it is to be used.

One important difference is simply size. Most CCPP's of recent design have been (nominally) 500 MW plants with a steam turbine providing approximately one-third of the plant output at design or about 170 MW. Coal-fired steam plants, on the other hand, range from 350 to 500 MW or larger and the entire output is provided by the steam turbine. Therefore, even neglecting differences in steam turbine heat rate, the heat load to be rejected through the ACC is typically two to three times greater at a steam plant than at a CCPP. While the equipment cost for an ACC is essentially linear with heat load, a significantly larger unit may have higher costs for extended steam supply ducting and a higher structure. This results from the need to elevate the fan deck more for a larger cluster of cells in order to provide free flow of air to the interior cells.

Another, and more important, distinction is the difference in steam turbine performance characteristics between the two plant types. Because of the higher steam turbine inlet pressure and temperature in steam plants, the turbines typically have lower heat rates, lower steam flow per unit output and shallower output correction curves (vs.

backpressure) than is the case with turbine designed for CCPP's. The comparison between the output correction curves is shown in Figure 3.

As a result of the lower reduction in output at elevated backpressure, the steam plant suffers less performance penalty during the hotter periods. The ACC therefore optimizes at a smaller size, higher ITD and lower cost per unit heat load. The optimum ITD's for the coal plants in this study ranged from 51 to 56 F as compared to 44 to 51 F for the combined-cycle plants.

## Cost of water

An important element in the cost comparison of wet vs. dry cooling is the cost of water. Sites for which dry cooling is considered are often those at which water is scarce, the water available for plant cooling may be of poor quality and the constraints on the discharge of wastewater may be severe. Therefore, is it not always appropriate to use nominal water and water-related capital and operating costs that have been typical of plants with cooling towers in water-rich regions.

The cost of water includes, in general, acquisition costs, delivery costs, in-plant treatment costs and discharge/disposal costs.

Table 4 summarizes the likely range of total water costs including acquisition, delivery and treatment.

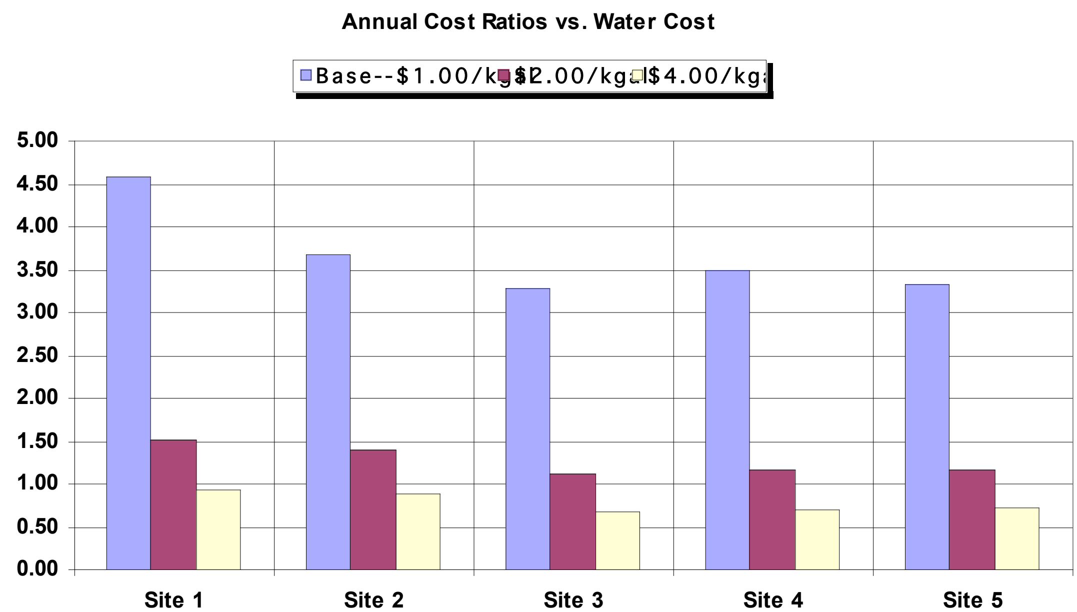
| Costs | Minimum | Low | Medium | High |
|---|---|---|---|---|
| | $/1,000 gallons | $/1,000 gallons | $/1,000 gallons | $/1,000 gallons |
| Acquisition | Nil | $0.50 | $1.25 | $3.00 |
| Delivery | Nil | $0.13 | $0.57 | $1.20 |
| Treatment/Disposal | $0.10 | $0.22 | $1.00 | $4.28 |
| **Total** | **$0.10** | **$0.85** | **$2.82** | **$8.48** |

**Table 4**
**Summary of Water Costs**

Establishing a realistic range is not completely straightforward. The lowest possible cost would be for water obtained under inexpensive water right purchases for good quality water requiring little treatment and adjacent to a site at which discharge to local receiving waters is permitted. For such a situation, a water cost of less than $0.25/1,000 gallon might be realistic.

At the other extreme, high cost leases for poor quality water requiring lengthy, up-hill pipeline transport to a zero-discharge site could theoretically result in water costs of, perhaps, $10/1,000 gallons. Neither extreme is likely to be common. For purposes of this study, water costs of from $1.00 to $4.00 per 1,000 gallons were considered. .

The cost of water can be one of the largest cost elements for wet cooling systems. The range of costs was discussed at length in Section 4. A base case cost of $1.00/kgal was chosen to be consistent with typical average costs for industrial water at the present time. However, higher costs are encountered in some locations and may become more prevalent at a wider range of places in the future. Therefore, the cost ratios were recalculated for water costs of $2.00/kgal and $4.00/kgal and plotted in Figure 7-8. At $2.00/kgal the annual cost ratios range from x 1.5 at Site 1 to x 1.4 at Site 2 to about x 1.1 for the other three sites. For $4.00/kgal water costs, dry cooling is favored at all sites with annual cost ratios ranging from x 0.9 to x 0.7 at the other sites. This suggests that the "breakeven" water cost at which wet and dry cooling have the same annual costs (for situations in which the rest of the base case values and assumptions apply) is between $2.00/kgal and $3.00/kgal.




## Additional Considerations

There are a number of additional considerations which can have a significant effect of the determination of an optimum design. Two of these, which are worthy of brief mention, are the business model and strategy adopted by the plant developer and the economic expectations regarding future average and peak period energy prices.

<u>Business strategy</u>

Plants may be built and operated by both regulated and non-regulated entities. The developer may expect to own the plant for its useful life or to sell it in a few years. These alternatives models affect the proper choice of the annualization factor which represents a tradeoff between initial capital and future operating and penalty costs.

Figure 9 indicates the effect of this annualization factor on the optimum for a dry system at Site 1. Higher factors increase the relative importance of the initial costs and drive the design to smaller ACC's and higher penalty costs.

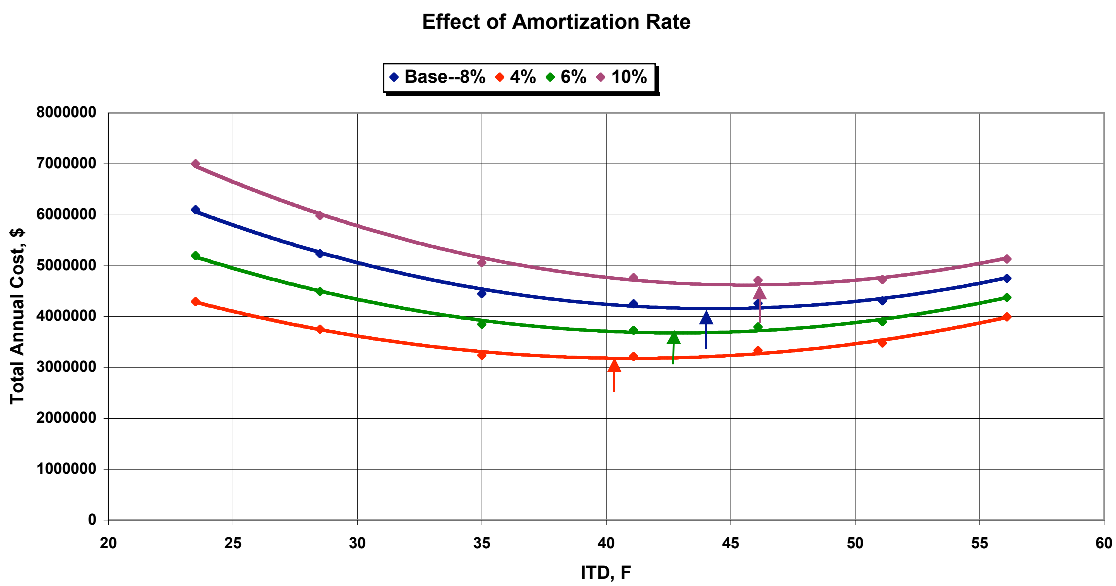



Figure 9: Effect of Annualization Factor

<u>Projected Energy Prices</u>

The expected average and peak energy prices have a very large effect on the projected penalty costs and, therefore, on the optimum design choice, as illustrated in Figures 10 and 11. While a peak power price of $550/MWh may seem excessive in today's markets, there is ample precedent for even higher prices in the recent past in California.

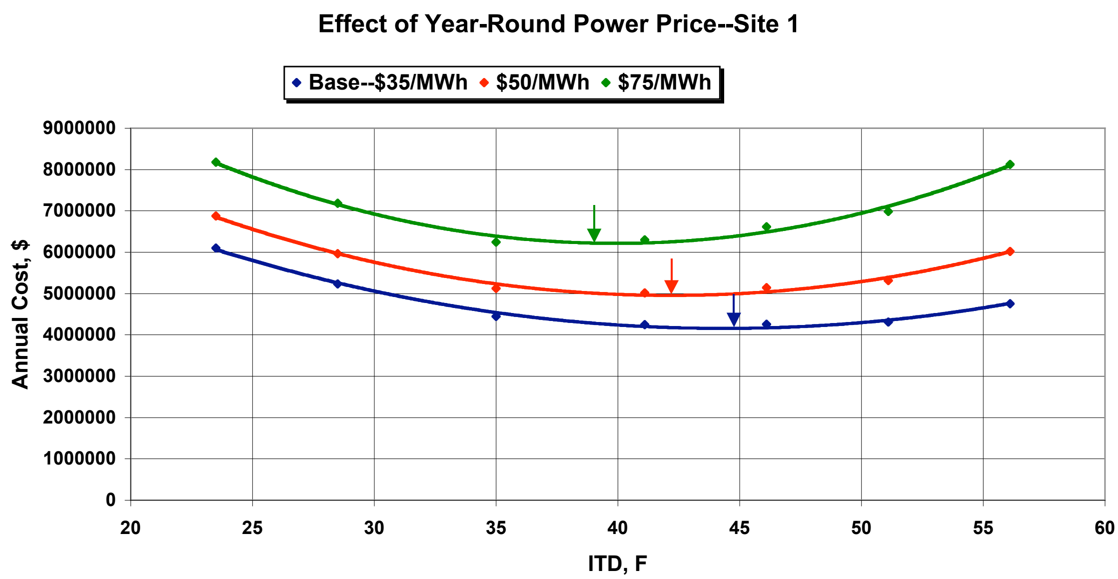



**Figure 10: Effect of Year-Round Power Price**

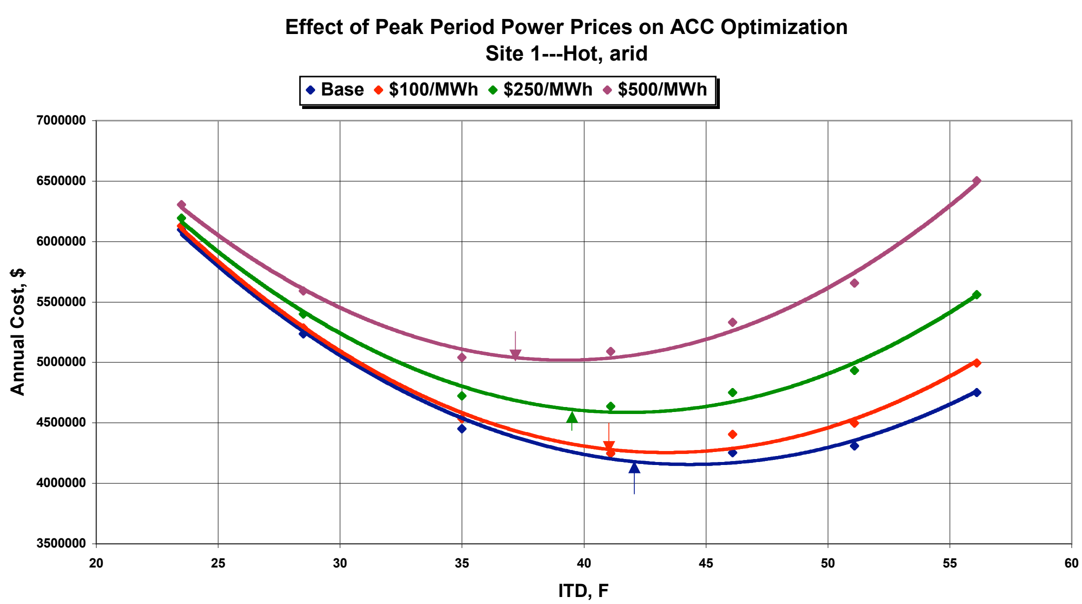



**Figure 11: Effect of Peak Power Price**

<u>Plant design and operating strategy</u>

Finally, a business strategy based on the ability to reap high revenues during peak periods may lead a developer to design and operate a plant to ensure full output on the hottest day. For a combined-cycle plant, this requires a means to augment or replace the lost power from the combustion turbines at high ambient temperatures. This is typically done with supplemental firing or "duct burning." The net result is that, on the hottest day, an increased portion of the plant load is borne by the steam side and the cooling system must be sized for a heat load which may be well in excess of the nominal "one-third of plant capacity."

## Hybrid Cooling

Hybrid cooling refers to systems with a conventional, shell-and-tube surface condenser and a wet cooling tower installed in parallel with an ACC, shown schematically in Figure 12.

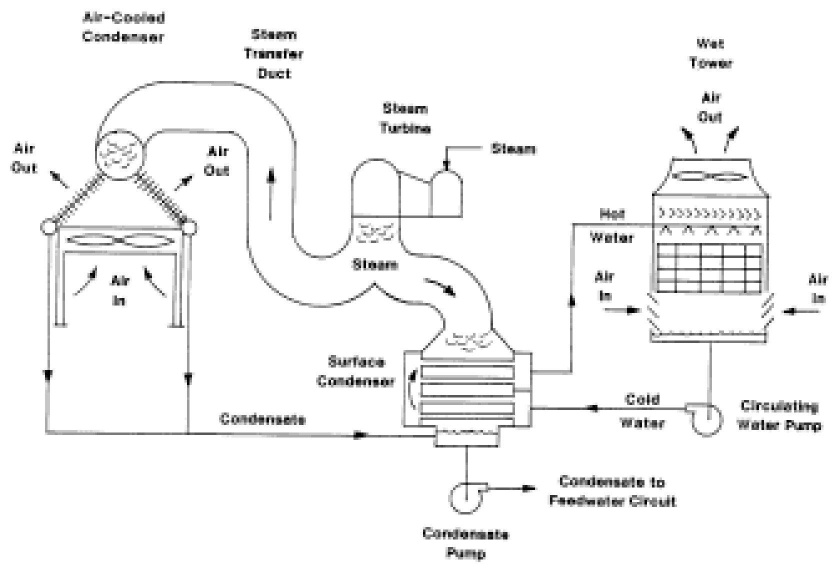



**Figure 12**
**Hybrid (Dry/Wet) Cooling System**

During peak load, hot periods, cooling water from the wet tower is circulated through the surface condenser which then draws steam away from the ACC. The system is self-balancing. The steam flow will divide to establish an operating point in which the condensing pressures in the ACC and surface condenser are the same. The heat load on the ACC is thus reduced and the turbine backpressure is lower than it would have been for an ACC operating alone.

The system permits the use of a smaller and therefore less expensive ACC than one which would have been required in an all-dry design. On the other hand, the system incurs the costs of the wet cooling system which, though small in size compared to what would be required for an all-wet system, requires the full complement of equipment including the shell-and-tube condenser, the cooling tower, circulating water pumps and piping, intake and discharge lines, structures and associated water treatment capability.

An in-depth discussion and analysis of the trade-offs is beyond the scope of this document. A more detailed discussion is available in the EPRI report [2]. General guidelines have been presented [3] which suggest that for annual water availability ranging from 15% to 85% of the water required for all-wet cooling, the capital cost of the hybrid system is less than that for an optimized all-dry ACC system.

## Summary

Water savings of approximately 2,800 acre-feet (~ 900 million gallons) per year can be achieved through the use of dry cooling at a 500 MW combined-cycle power plant. At a 350 MW coal-fired plant, the annual savings are approximately 6,400 acre-feet (~ 2 billion gallons) The capital cost of the dry cooling system ranges from $21 to $26 million for the combined-cycle plant compared to $5.7 to $6.5 million for wet cooling. The capital cost ratio ranges from 4.5 at a hot, arid site to about 3.5 at more moderate sites. Dry cooling imposes a heat rate penalty on the plant which can range from 25% on the hottest hour of the year and exceed 8% for over 1,000 hours at a hot, arid site. On an annual basis, the plant output is reduced by about 2%. For base case operating and economic assumptions, the "cost of water saved" ranges from $1,100 to $1,400 per acre-foot or $3.50 to $4.50 per 1,000 gallons.

## References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2. EPRI, "Comparison of Alternate Cooling Technologies for U. S. Power Plants: Economic, Environmental and Other Tradeoffs", EPRI Report No. 1005358, 2004
3. Sanderlin, D. and F. Ortega, "Dry Cooling History in North American Power Plants", Presented at AWMA Workshop on "Dry Cooling for Power Plants---Is This the Future?", May, 2002
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